BEFORE THE PUBLIC SERVICE COMMISSION
OF SOUTH CAROLINA

DOCKET NO. 2019-185-E
DOCKET NO. 2019-186-E

In the Matter of South Carolina Energy Freedom Act (H.3659) Proceeding to Establish Duke Energy Carolinas, LLC's and Duke Energy Progress LLC's Standard Offer Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and Any Other Terms or Conditions Necessary (Includes Small Power Producers as Defined in 16 United States Code 796, as Amended) – S.C. Code Ann. Section 58-41-20(A)	))))))))))))))	**REBUTTAL TESTIMONY OF JOHN SAMUEL HOLEMAN III ON BEHALF OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC**

Q. PLEASE STATE YOUR FULL NAME AND BUSINESS ADDRESS.

A. My name is John Samuel Holeman III (Sam). My business address is 526 South Church Street, Charlotte, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed as the Vice President of the System Planning and Operations Department for Duke Energy Corporation ("Duke Energy"). In that capacity, I oversee the planning and operations for Duke Energy's regulated electric utilities' electrical systems, including Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, the "Companies" or "Duke").

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND.

A. I graduated from Clemson University in 1983 with a B.S. Degree in Electrical Engineering and in 1985 with a M.S. Degree in Electrical Engineering. I also obtained a Master of Business Administration Degree from Queens University in 2014. I am a registered Professional Engineer in North Carolina and South Carolina. I am also a member of the Institute of Electrical and Electronics Engineers.

Q. PLEASE SUMMARIZE YOUR ENGINEERING AND TECHNICAL BACKGROUND AND EXPERIENCE.

A. I joined Duke Energy in 1985 and have held various engineering and management positions in System Planning and Operations of increasing responsibility throughout my career. These positions include: EMS

Application Engineer; System Operating Center Engineer; System Operator; Manager, System Operating Center; Director, System Operating Center; and Director, Engineering and Training. In my current position, as Vice President – System Planning and Operations, I am responsible for compliance with the North American Electric Reliability Corporation ("NERC") and Federal Energy Regulatory Commission ("FERC") safety and reliability regulations applicable to Balancing Authority and Transmission Operator functions, as well as planning and operations for Duke Energy's regulated electric jurisdictions.

I have also been extensively involved with and now manage the ongoing NERC and SERC Reliability Corporation ("SERC") system operations compliance obligations for Duke Energy's regulated electric utilities. I served as Chair of the SERC Operating Committee from 2007 through 2009, and was also Chair of the NERC Operating Committee from 2009 through 2011. I also served as the NERC Event Analysis Subcommittee Chair from 2012 to 2014 and served on the NERC Essential Reliability Services Task Force from 2014 to 2015.

Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY WITH THE COMMISSION IN THESE PROCEEDINGS?

A. No, I did not. I also have not previously testified before the Public Service Commission of South Carolina ("Commission"). However, I did recently testify before the North Carolina Utilities Commission ("NCUC") in a similar proceeding in the spring of 2017, during that state's 2016-2017 review of North Carolina's implementation of the Public Utilities Regulatory Policy Act

("PURPA") for DEC and DEP. I highlight this prior North Carolina testimony because the Companies operate their power systems across NERC Balancing Authorities ("BAs") that encompass the DEC and DEP service territories across both states. My testimony before the Commission is similar to my prior testimony in North Carolina because the new technical challenges and operational circumstances facing the Companies' system operators as growing levels of uncontrolled solar qualifying facilities ("QFs") interconnect and to inject power into the DEC and DEP grids exists regardless of whether the new solar generation is added in South Carolina or North Carolina.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony responds to arguments and testimony put forward by Office of Regulatory Staff ("ORS") Witness Brian Horii, Southern Alliance for Clean Energy and Coastal Conservation League ("SACE/CCL") Witness Brendan Kirby, and South Carolina Solar Business Alliance ("SBA") Witness Ed Burgess. While each of these witnesses presents varying levels of understanding of power system operations, my testimony addresses my experience actually overseeing operations of the DEC and DEP power system as significant QF solar has been added in recent years.

Q. PLEASE SUMMARIZE YOU REBUTTAL TESTIMONY.

A. First, my rebuttal testimony provides the Commission information on the Companies' operations of the DEC and DEP BAs, as well as the Companies' growing experience with the operational concerns, reliability risks, and NERC compliance challenges associated with the rapid and ongoing deployment of solar QFs that are continuing to interconnect with and inject energy into the Companies' systems under PURPA. Next, my rebuttal testimony addresses the mandatory and enforceable NERC Balancing ("BAL") Standards raised by other witnesses in this proceeding and explains that the DEC BA and DEP BA must each carry operating reserves to ensure compliance with the NERC BAL Standards on a real-time basis. In connection with providing this foundational understanding of the functions that BAs must perform in order to maintain power system reliability and compliance with NERC's BAL Standards, I address the operational impacts from integrating unscheduled and unconstrained energy from QF solar, and will show that ORS Witness Horii is correct in recognizing that solar generation requires additional ramping capability and reserves to meet both the intermittent nature and diurnal ramping characteristics of solar generation.[1] I will also explain why reducing solar integration costs is much more difficult than as postulated by Witness Horii, and describe how Duke is committed to undertaking reasonable and prudent efforts to address the new challenges of managing intermittent solar operations.

I then respond to SACE/CCL Witness Kirby's perspective regarding the Companies' obligations and allowed flexibility to comply with the NERC BAL standards. I also rebut his assertion that the DEC and DEP BAs can use off-line contingency reserves to lower the cost of operating reserves necessary to

[1] ORS Horii Direct, at 19.

comply with NERC's BAL Standards and thus lower the cost of integrating intermittent solar generation into the DEC and DEP BAs.

Finally, I rebut SBA Witness Burgess' assertion that the DEP-East and DEP-West Balancing Authority Areas[2] should be viewed as separate BAs (which they are not) for purposes of calculating DEP's avoided cost rates in this proceeding. I will then rebut Witness Burgess' assertion that the system operator can reliably plan and operate the BAs, assuming use of the full 30 consecutive minute period to economically optimize the control of generation resources for meeting compliance with the NERC Standard BAL-001-2 Balancing Authority area control error ("ACE") requirement. I also rebut Witness Burgess's assertion that QF solar can be used as a dispatchable resource to provide regulation and load following services based on a one-day demonstration at a 300 MW First Solar plant in CAISO. Additionally, I will rebut Witness Burgess' conclusion that operating reserves have not increased as more solar has been integrated in the Carolinas.

Q. ARE YOU INCLUDING ANY EXHIBITS IN SUPPORT OF YOUR REBUTTAL TESTIMONY?

A. No.

[2] The official name of the DEP-East BAA is CPLE and the DEP-West BAA is CPLW but, my testimony uses DEP-East and DEP-West for ease of reference.

I. DUKE'S RESPONSIBILITIES AS NERC BALANCING AUTHORITIES

Q. PLEASE DESCRIBE DEC'S AND DEP'S NERC RESPONSIBILITIES GENERALLY.

A. In addition to its operations as a BA (which I discuss further below), DEC and DEP perform various additional NERC reliability functions. As a generator owner and operator, DEC and DEP own, maintain, and operate generating units to supply reliable and affordable electricity to approximately 4 million customers in South Carolina and North Carolina. As a transmission owner and operator, DEC and DEP own, maintain, and operate transmission facilities in South Carolina and North Carolina, and are responsible for operating the transmission system in a reliable manner in compliance with applicable NERC reliability standards. In my role as Vice President for System Planning and Operations, I am directly responsible for ensuring the Companies' ongoing compliance with the NERC reliability standards applicable to Balancing Authority and Transmission Operator functions.

Q. PLEASE EXPLAIN THE COMPANIES' ROLES AS NERC BALANCING AUTHORITIES FOR THEIR BALANCING AUTHORITY AREAS.

A. DEC and DEP are each independent NERC Balancing Authorities responsible for maintaining reliable operations on their systems, as well as managing power flows between their systems and other utility systems.[3] DEC operates a fleet of approximately 22,200 MW (winter rating) of MW resources to serve customers' energy needs on a 20,455 MW peak load system, while DEP operates approximately 17,200 MW (winter rating) of MW resources to serve its customers' energy needs on a 16,429 MW peak load system.

The DEC and DEP BAs independently control their respective generating fleets of "network resources" to meet system loads, as well as to maintain compliance with NERC reliability standards applicable to each BA. This includes maintaining interchange schedules between the DEC BA and the DEP BA, as well as other neighboring BAs, such as the Southern Company, Dominion Energy South Carolina and South Carolina Public Service Authority BAs to the south, the Tennessee Valley Authority BA to the west, and the PJM Interconnection BA to the north.

Each BA is responsible for independently complying with its mandatory NERC obligations, including providing its share of frequency support for the Eastern Interconnection, and by definition, maintaining demand and resource balance within its Balancing Authority Area. A Balancing Authority must purposefully plan and dispatch its generating fleet to ensure compliance with NERC BAL standards and cannot rely on unscheduled power flow from neighboring BAs to meet its obligation to maintain demand and resource

[3] The Balancing Authority is defined by NERC as "[t]he responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time." *Available at:* http://www.nerc.com/pa/Stand/Glossary of Terms/Glossary_of_Terms.pdf..

balance. Thus, the NERC BAL Standards are designed to discourage this behavior.

DEC and DEP are each subject to mandatory NERC regulations, requiring the Companies to independently balance their respective systems and to provide reliable "firm native load service" to meet customers' electricity needs.

Q. PLEASE EXPLAIN DUKE'S SYSTEM OPERATORS' ROLE IN RELIABLY OPERATING DEC'S AND DEP'S GENERATING FLEETS TO MEET CUSTOMERS' ENERGY NEEDS.

A. The Duke system operators are a dedicated group of 40 employees that manage DEC's and DEP's respective generating fleets to ensure reliable system operations are maintained. The system operators for each BA must independently maintain a Security Constrained Unit Commitment of base-load and load-following assets, regulation resources, operating reserves, and spinning reserves, working together to plan for and meet customers' energy needs in real time, and to also ensure real-time frequency support and balancing is maintained. The system operators' core responsibility is to manage the independent DEC and DEP BAs, by balancing generation resources, unscheduled energy injections (from solar QFs), and load demand in real-time in order to provide reliable firm native load service, maintain compliance with mandatory reliability standards, and achieve reliable bulk electric system operations across the Eastern Interconnection.

Q. PLEASE DESCRIBE THE ESSENTIAL RELIABILITY SERVICES THAT DEC AND DEP MUST PROVIDE TO MAINTAIN SAFE AND RELIABLE ELECTRIC SERVICE UNDER NERC REGULATIONS.

A. Essential reliability services are elemental reliability building blocks integral to providing reliable electric service to customers and protecting system equipment. These essential reliability services include: (i) voltage support; (ii) system inertia; (iii) ramping; and (iv) frequency support. They are "essential" because they are critical to reliable BA operations and must be provided regardless of the BA's resource mix. Observing the potential for significant penetrations of variable energy resources (such as solar in the Carolinas) to impact necessary reliability services delivered by large rotating mass synchronous generators essential for reliable electric system operations, NERC established the Essential Reliability Services Task Force in June 2014 to examine these essential reliability services and develop standards for their application. Essential reliability services are provided by designated network and contingency resources that have synchronous, load-following response capabilities and are measured and monitored to comply with NERC requirements, so that operators and planners are aware of the changing characteristics of the BA, and can make informed decisions to operate the BA in a reliable manner.

Q. PLEASE EXPLAIN HOW THE DEC AND DEP SYSTEM OPERATORS CONFIGURE AND COMMIT DEC'S AND DEP'S LOAD FOLLOWING GENERATION ASSETS TO PROVIDE THESE ESSENTIAL RELIABILITY SERVICES.

A. DEC's and DEP's system operators must plan and operate the Companies' generating resources to reliably meet increasing and decreasing intra-day and day-ahead system loads within reliability and generating unit availability and operating limits. To meet this objective, DEC and DEP must independently plan for and maintain three general categories of reliability and load-following network resources. Each BA's operators select resources to reliably meet demand and provide firm native load service, referred to as the "Security Constrained Unit Commitment," consisting of the following:

(i) <u>Base-Load and Must-Run Regulation Resources</u>

(a) <u>*Base-Load Firm Native Load Resources*</u>. These are the generating resources (such as nuclear, coal, and large natural gas combined cycle units) that form the foundation of reliable service to meet the core system demand. They deliver the foundational system inertial response, and must operate within specified levels to provide stability against disturbances. *For reliability, these units cannot be de-committed in real-time nor on an intra-day basis.* As I discuss further below, as solar QF-caused operationally excess energy increases on the Companies' systems, these units cannot be de-committed at mid-day to accommodate the excess QF energy and then return to service for the evening or next morning peak demand.

(b) *__Must-Run Regulation and Regulation Reserves Resources__*. These are generating resources (coal, gas combined cycle, and combustion turbine generation operating below full output) that provide load balancing regulation (*e.g.*, balancing the BA Area Control Error ("ACE")) and frequency regulation support to maintain reliability by supporting system frequency to the required target of 60 Hz in compliance with mandatory NERC Reliability Standards. Similarly, in respect to the solar QF-caused operationally excess energy, the coal and combined cycle generating resources needed to ensure regulation is available to meet the DEC BA and DEP BA obligations would not be de-committed at mid-day to accommodate the excess QF energy and then return to service for the evening or next morning peak demand.

These "Base-Load Firm Native Load Resources" and "Must-Run Regulation and Regulation Reserves Resources," together, represent the first of three general categories of reliability and load-following network resources. The base-load and must-run regulation units specifically represent the foundational resources necessary to meet load requirements, provide reliability, and meet mandatory NERC Reliability Standards. In the aggregate, the operationally constrained minimum reliable output of these generators represents the lowest reliability operating level ("LROL") of the BA's Security Constrained Unit Commitment. *These essential generating resources would not be de-committed in real time nor on an intra-day basis, because they must run within specified engineering levels and provide the essential frequency and* *regulation support to the BA, and because they are needed to meet upcoming peak demands, such as the evening peak demands and next day peak demands*.

(ii) <u>Operating Reserves Resources</u>

These are the load-following resources and reserves that provide for capability above firm system demand required to provide for regulation, load forecasting error, forced and scheduled outages, and local area protection. Generally, these units are available above the LROL output of the system's essential reliability generating resources. Traditionally, these resources were selected and maintained on a day-to-day basis and were capable of providing energy to the system when the actual system load deviated from forecasted load. Now, however, these assets are also increasingly being required to operate in real time to adjust for solar energy injections into or withdrawals from the BA.

(iii) <u>Spinning Reserves</u>

These are fossil (coal and natural gas) and hydroelectric generation units that are online providing real-time spinning, regulation, and frequency reserves in response to real-time changes in customer load demand, and now increasingly responding to the intermittency of unscheduled solar energy injections into the system. These resources were installed to respond to the minute-by-minute variability in system load demand; however, they are now also responding to the intermittency of solar generation.

II. DUKE'S OPERATIONAL EXPERIENCE INTEGRATING QF SOLAR

Q. PLEASE DESCRIBE THE CHALLENGES THE DEC AND DEP BAs ARE INCREASINGLY FACING BASED UPON YOUR RECENT EXPERIENCE INTEGRATING UTILITY-SCALE SOLAR INTO THE COMPANIES' SYSTEM OPERATIONS.

A. As the BA operator, DEP must balance the entire BA, and therefore, must balance for all installed solar capacity, whether interconnected directly to the South Carolina or North Carolina region of DEP's BA, or even to DEP's wholesale customers to whom DEP must also provide firm native load service. The level of installed solar injecting energy into the DEC BAs and DEP BAs has rapidly increased, particularly in North Carolina over the past five years due to that state's renewable energy policies and PURPA implementation.

The majority of this solar has been developed in DEP East, with over 2,400 MW of installed solar capacity interconnected and now injecting energy into the DEP system as of August 31, 2018. An additional 1,032 MW are currently under construction in DEP, with significant QF solar proposed to be developed in the future in both South Carolina and North Carolina. Installed utility-scale QF solar (plants $1MW_{AC}$ or greater) continues to grow with over 3,300 MW installed in the combined DEC and DEP BAs, and with over 10,000 MW requesting interconnection to be installed in the future. Based upon current solar QFs under construction and in development, the level of installed PURPA solar across both states is projected to continue to grow over the next few years

– increasing to over 3,400 MW of installed PURPA solar capacity for DEP and to over 1,800 MW of installed PURPA solar capacity for DEC by 2022.

Based on the Companies' growing operational experience maintaining essential reliability service and operating the BA in accordance with NERC's reliability requirements as significant growth of uncontrolled PURPA QFs has continued, the Companies have identified the following challenges associated with integrating significant levels of PURPA solar: (i) managing "unscheduled" and "unconstrained" solar QF energy injections bounded by the Security Constrained Unit Commitment of reliable load-following service; (ii) managing the variability and intermittency of solar energy injections; (iii) managing the growing amounts of operationally excess energy injected by solar facilities, particularly during the spring, fall, and winter periods; and (iv) ensuring compliance with NERC reliability standards, specifically including the BAL standards.

Q. PLEASE EXPLAIN WHAT THE COMPANIES MEAN BY "UNSCHEDULED" AND "UNCONSTRAINED" SOLAR QF ENERGY, AND WHY IT IS NOW IMPACTING THE RELIABILITY OF SYSTEM OPERATIONS.

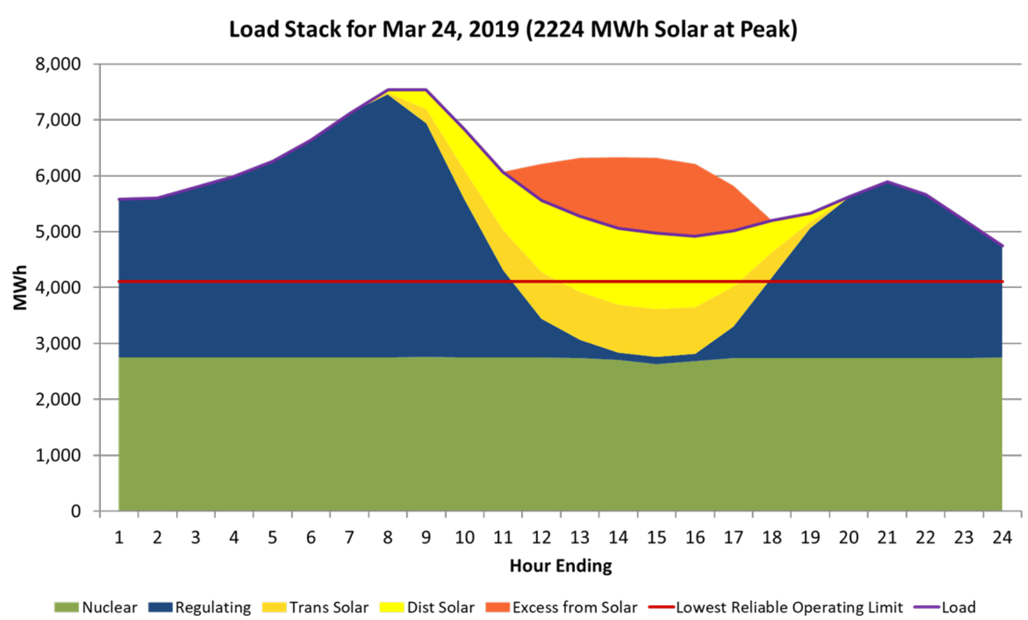
A. Solar QFs inject energy into the BA without any day-ahead or intra-day scheduling coordination with the system operator and without any commitment to deliver scheduled quantities of energy into the BA, and therefore, are making "unscheduled" energy injections into the BA. Moreover, the unscheduled solar QF energy injections into the BAs are "unconstrained" by dispatch control due to PURPA's curtailment limitations. While I am not an attorney, it is my understanding and operational experience that, absent contractual agreement otherwise, a QF injecting energy into a system under a contract may be curtailed and the energy injections discontinued only in a "system emergency." Thus, while PURPA limits the system operator's control over these increasingly significant penetrations of QF solar energy resources, the BA must still be balanced in real time, and therefore, the BA system operator must continuously dispatch the output of its network resources to respond to the increases or decreases in the solar QF energy injections. The Companies' recent experience is that the real-time balancing of the system is becoming increasingly volatile due to large and uncertain swings in the unscheduled and unconstrained solar QF energy injections into the BA, thus requiring the system operator to utilize additional operating reserves to ensure compliance with NERC reliability standards.

Q. WHY ARE THE COMPANIES CHALLENGED TO PREDICT THE OUTPUT OF UNSCHEDULED AND UNCONSTRAINED SOLAR QFs AND WHAT IMPLICATIONS DOES THAT UNPREDICTABILITY HAVE FOR OPERATING THE SYSTEM IN REAL TIME?

A. The fuel supply for solar generating plants is solar irradiance (intensity of sunshine), which effectively means the ultimate energy source for solar is intermittent because the generating facility operator (whether the Companies or a third party) cannot control the fuel supply. Therefore, the solar plants' production levels are less predictable than load patterns, and the production levels have no coincidence with load patterns. Ultimately the BA operator has limited tools to maintain reliability in the face of these unscheduled and unconstrained injections of QF energy.

Because solar QF energy is both unscheduled for day-ahead and intra-day operational planning and is unconstrained for reliability dispatch control purposes, except for emergency conditions, system operators must plan for and BA load-following generating resources must react to provide balancing and ancillary services such as regulation and frequency response. However, there are also physical limitations to the BA's capability to reliably operate and absorb such unscheduled and unconstrained energy injections. My Figure 1 depicts actually-experienced limits for the DEP BA integrating QF solar to serve customer load during a recent day in March 2019.

Figure 1



As I explained above, in planning to serve system load, the DEP system operator selects a Security Constrained Unit Commitment that is necessary to reliably provide firm native load service in the DEP BA. The Security Constrained Unit Commitment's LROL, below which the BA *cannot* reduce operational output, *must* be retained through the mid-day valley of the demand curve each day to provide for: (i) frequency regulation and maintaining real-time balance of demand and resources; (ii) resource availability to meet the evening peak demand, as well as; (iii) resource availability to meet the next morning's peak demand, which is generally higher than the previous evening's peak demand. The LROL is illustrated in Figure 1 by the horizontal red line. DEP's actual native load system demand (purple line above load) is above the LROL, but the DEP system operator must also manage the unscheduled and unconstrained real-time solar QF injections into the BA creating a "net" demand on the system below the LROL, thereby causing operationally excess energy (depicted in orange), which I discuss in more detail later.

Q. PLEASE DESCRIBE HOW THE DEP SYSTEM OPERATORS ARE MANAGING THE SIGNIFICANT ADDITIONAL GROWTH IN UNSCHEDULED AND UNCONSTRAINED PURPA SOLAR.

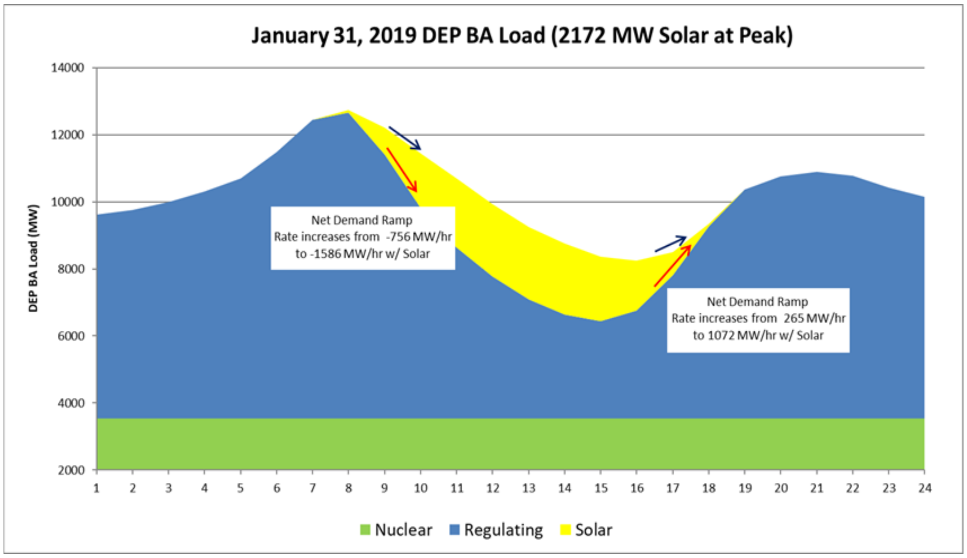
A. Currently, the DEP BA is continuing to experience significant growth of unplanned solar QFs. These facilities maximize their output and continue to inject energy into the BA during the mid-day load valley when system demand is at its lowest. The BA cannot reduce its LROL level, causing system generation required for reliability to exceed the net system demand (actual load minus unscheduled/unconstrained solar QF energy), resulting in operationally excessive energy on the BA – *caused by operationally excessive solar QF installed capacity*. In the Figure 1 illustration above, the operationally excessive energy is all of the solar energy (yellow shading) in the trough below the LROL (red horizontal line).

The levels of unconstrained solar energy already being experienced during mid-day hours on certain non-summer days are forcing DEP to either: (i) increasingly ramp and cycle its intermediate and non-nuclear base load generators; and/or (ii) to sell the operationally excess solar QF energy into a neighboring BA using non-firm transmission, if available and if such transmission is not curtailed. Both of these options create potential real-time operating and reliability complexities and challenges. Looking ahead to 2020 and beyond, these challenges and risks will be amplified, particularly in the DEP BA, as the quantity of installed solar QF capacity increases.

Q. PLEASE DESCRIBE HOW THE BA MAINTAINS REAL-TIME BALANCING OF DEMAND AND GENERATION AS VARIABLE QUANTITIES OF UNSCHEDULED AND UNCONSTRAINED SOLAR ENERGY IS INJECTED INTO AND WITHDRAWN FROM THE BA.

A. Solar generators, by their nature, deliver variable quantities (i.e., low forecast certainty) of unscheduled and unconstrained energy into the BA throughout the day (see my Figures 3 and 4 below), and most commonly inject their peak outputs of energy during mid-day hours when the sun is normally providing highest irradiance.

Figure 2



As Figure 2 shows, in the morning as the solar facilities begin to inject energy, the BA must rapidly start ramping down its resources that were online to serve the morning peak demands. This ramp down is accomplished by rapidly reducing network resource output in the opposite direction of the solar energy delivery curve. Correspondingly, in the afternoon, as system demand gains, the solar generation begins to fade and drop off. To balance the system in real time, the BA must rapidly ramp up the output of its fossil fuel resources to catch the rapidly rising demand and support the evening peak load, while the solar generation is also rapidly dropping off.

Figure 2 represents an actual winter day in the DEP BA with peak demand of more than 12,736 MW and 2,172 MW of solar installed capacity. It shows the morning peak was served only by DEP's load following network resources, with very limited, if any, contribution to peak demand by the solar installed capacity. After the morning peak, the solar generation increases significantly, requiring steep down-ramps of DEP's fossil fuel resources, with increased risk of excess energy on the system if DEP is unable to take generation off-line fast enough as solar generation injections increase; at the same time, DEP must also maintain proper online operating reserves should cloud cover suddenly decrease the solar output.

Managing these operational limitations of QF solar presents a significant challenge for the system operator. Figure 2 shows that the majority of the solar generation is produced during the mid-day hours when the system has the least need for energy, and therefore, increases the risk of operationally excessive energy on the system. Lastly, Figure 2 shows a rapid drop off in solar energy production in the afternoon hours, requiring steep ramping of network resources, and an increased risk of deficit energy on the system if DEP's fossil fuel resources are unable to keep pace with increasing demand and the rapidly fading solar generation.

Q. PLEASE EXPLAIN HOW FIGURE 2 SHOWS THE NEED FOR INCREASED RAMPING CAPABILITY TO MANAGE THE OPERATIONAL IMPACTS OF SOLAR INTEGRATION.

A. Figure 2 presents a real-world example of the challenging ramping requirements that DEP is increasingly experiencing as unconstrained solar QF penetration levels increase in the BA. For this January 2019 day, and similarly for many fall, winter, and spring load shape days, the BA has historically experienced rapid up-ramp requirements in the late afternoon, early evening hours 16:00 to 20:00 ("late day period") due to customer load demand. As significant uncontrolled QF solar has been installed in the DEP BA, this late day period when customer load demand is ramping up is also when the solar QF energy injections into the BA are rapidly declining. In the late day period, the BA's load-following resources are operating at low output levels to accommodate QF energy injections; as a result, the BA must meet increasingly steeper "net" ramping requirements to: (i) satisfy higher customer demands, and (ii) back-stand the deficit due to rapidly declining QF energy injections. This requires the utilization of more on-line operating reserves to ensure compliance with the NERC BAL standards.

Q. PLEASE EXPLAIN HOW THE OPERATIONAL CIRCUMSTANCES YOU ARE DESCRIBING IN YOUR FIGURE 2 CREATE THE NEED FOR DEC AND DEP TO MAINTAIN INCREASED ON-LINE OPERATING RESERVES TO MANAGE THE OPERATIONAL IMPACTS OF SOLAR INTEGRATION.

A. In addition to the operational impacts to net demand ramping, the variability and intermittency of QF solar injections creates the need for additional operating reserves to be utilized in order to ensure compliance with the NERC BAL standards. As shown in my Figures 3 and 4, the actual solar output for two consecutive seven-day periods in February and March 2019 reflect this variability and intermittency that Duke Energy's system operators must prepare for and respond to with planning and utilization of operating reserves to ensure compliance with the NERC BAL Standards. High concentrations of a single type of resource, such as solar QFs, create imbalance in the portfolio and higher operating risks due to its generating characteristics. For illustrative purposes, Figures 3 and 4 below shows the output from the same set of solar generators (approximately 2,400 MW of nameplate solar capacity) injecting unscheduled and unconstrained energy into the DEP BA over two different seven-day periods during February and March 2019.

Figure 3

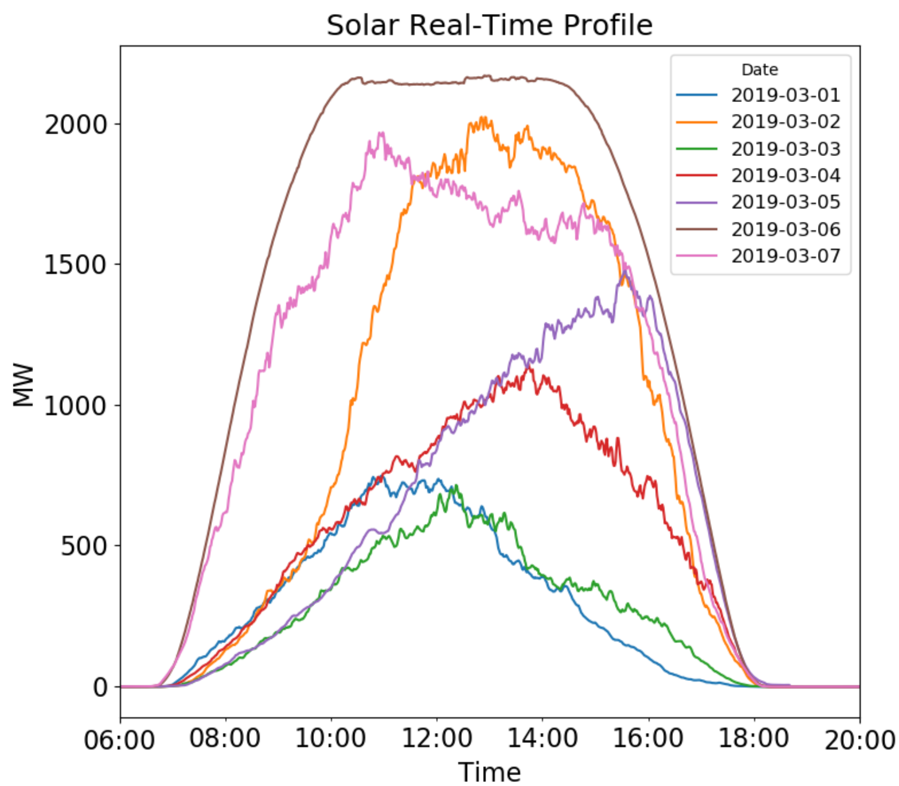


Figure 4

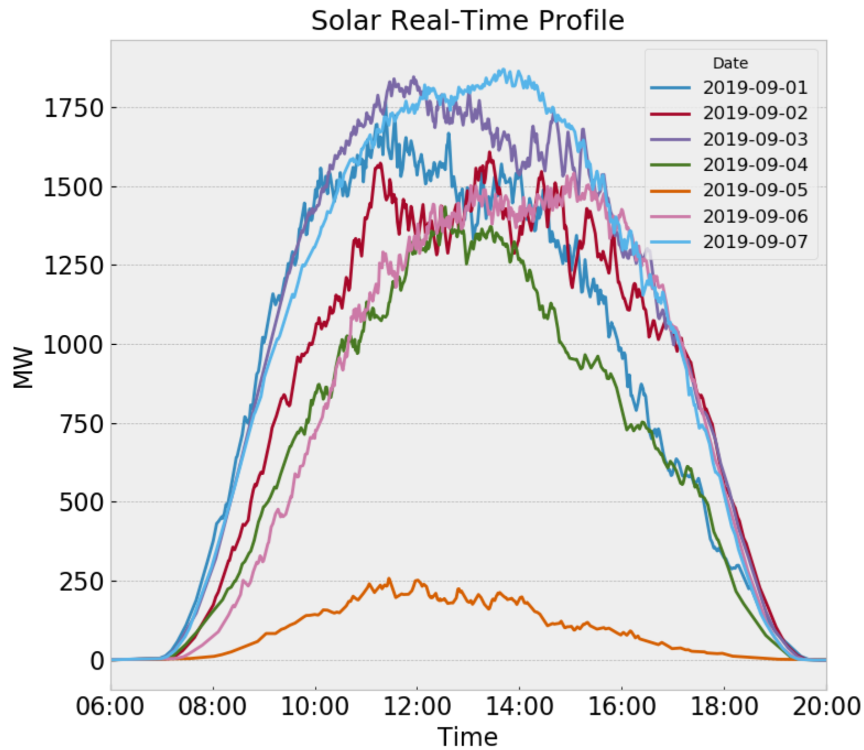


Figure 3 shows the significant output volatility experienced during a spring 2019 week of March1-7, 2019, with the solar QF generators injecting up to 2,243 MW of output and as little as 527 MW of peak output over that seven-day period. Figure 4 similarly shows significant volatility of solar output during a recent fall week of September 1-7, 2019, with the solar QF generators injecting up to 1,870 MW of output and as little as 257 MW of peak output over that seven-day period. The "jagged" nature of the chart lines shows that the uncontrolled solar generation output has minute-by-minute volatility – which I refer to as "intermittency." The difference in production over the seven-day periods shows output variation from the same set of solar generators on a day-to-day basis and on an intra-day basis – which I refer to as "variability." Figures

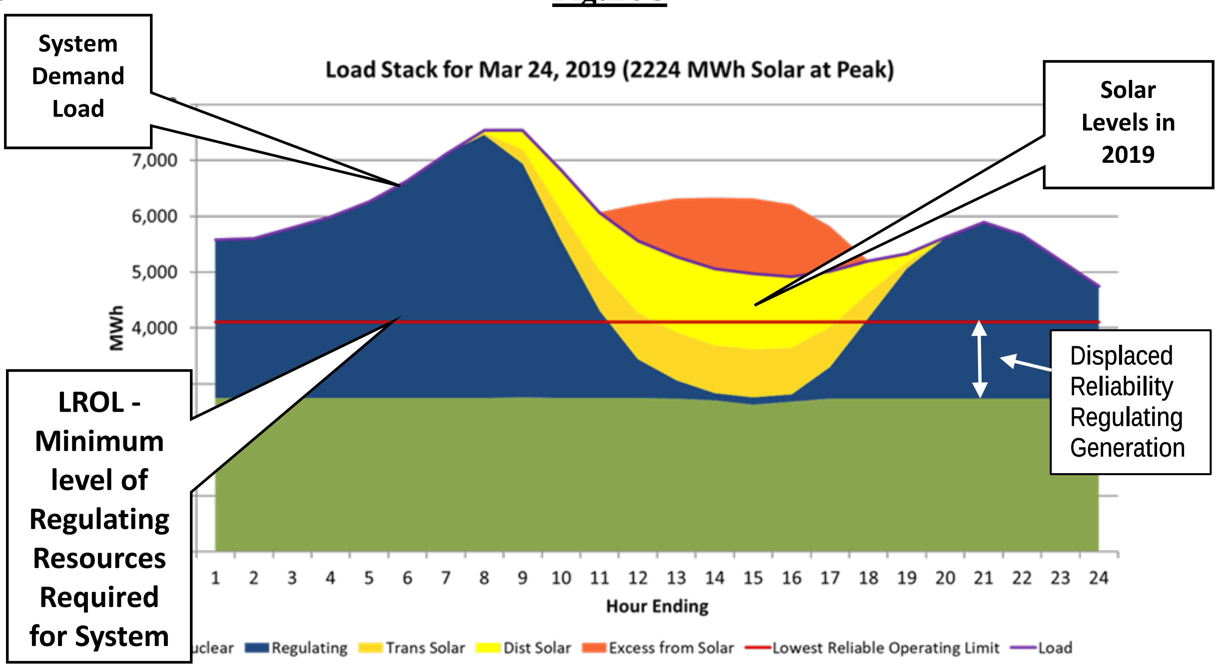
3 and 4 also show that on some days the generators may follow a typical intra-day curve requiring an increasingly steep morning ramp-down and increasingly steep afternoon ramp-ups, however, more frequently, other days have more volatile intra-day unscheduled injections requiring the BA's load-following assets to rapidly ramp up and down to balance resources and demand on an intra-hour basis.

The data presented in Figures 3 and 4 demonstrate that solar capacity is operationally unreliable with significant day-ahead and real-time energy production variability, volatility, and intermittency, because of their dependence on solar irradiance. In order to respond to the increased variability and intermittency DEP is experiencing as solar capacity additions have increased, DEP system operators been required to utilize more online operating reserves to ensure reliable system operations.

Q. ARE DEC AND DEP ALSO EXPERIENCING INJECTIONS OF SOLAR ENERGY INTO THEIR RESPECTIVE BALANCING AREAS IN EXCESS OF DEC OR DEP'S ABILITY TO RELIABLY ABSORB THE INJECTED ENERGY?

A. Yes. I described earlier that "operationally excess energy" is another challenge that DEP system operators are experiencing during an increasing number of days and hours throughout the year. My Figure 5 below illustrates a recent spring day in the DEP BA where the energy injected into the BA by the approximately 2,400 MW of solar capacity installations exceeded the system's load demands and capability to absorb such energy injections, while also maintaining the LROL level of non-variable and non-intermittent load-following dispatchable resources required to provide firm load-following service to customers and ensure the system is operating in a reliable manner. The red line bisecting Figure 5 delineates the actually-experienced operationally excess energy that resulted during the morning and mid-day hours due to the need to maintain the LROL minimum level of regulating resources required for system reliability online during peak solar output in order to ensure sufficient resources on-line to meet afternoon ramping requirements.

Figure 5



As the level of variable and uncontrolled solar on the BA increases, the number of days and hours throughout the year when operationally excess energy occurs is also increasing. During calendar year 2018, there were 576 hours when the DEP BA had operationally excess energy due to unscheduled and unconstrained solar QF injections. Through August 2019, the DEP BA has already eclipsed all of calendar year 2018, with approximately 652 hours when the DEP BA had operationally excess energy due to unscheduled and unconstrained solar QF injections.

Q. WILL THE GROWING LEVELS OF UNSCHEDULED AND UNCONSTRAINED OPERATIONALLY EXCESS SOLAR QF ENERGY CHALLENGE FUTURE COMPLIANCE WITH NERC'S RELIABILITY STANDARDS?

A. Yes. Maintaining compliance with mandatory NERC reliability standards is critically important and requires the BA to maintain proper generation reserves and to balance demand and resources in real time. The growing levels and instances of operational excess generation associated with solar QFs, as described above, directly impact and challenge DEP's, and eventually DEC's, ability to plan for and assure compliance with NERC's reliability standards.

III. <u>THE NERC BAL STANDARDS</u>

Q. PLEASE EXPLAIN THE IMPORTANCE OF NERC'S BAL STANDARDS AS THEY APPLY TO MAINTAINING SYSTEM RELIABILITY.

A. DEC and DEP must comply with all applicable NERC reliability standards and associated requirements, including the BAL standards. Together, the BAL-001, BAL-002, and BAL-003 standards are designed to enhance the reliability of each Interconnection by maintaining frequency within predefined limits every 30 minutes under all conditions, and effectively mandate every BA to balance generation resources to load demand within the BA during each 30-minute reporting period. The purpose of BAL-001 is to maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply resources in real time and, as needed, to take action to support reliability.[4] These standards demonstrate NERC's focus on the importance of properly regulating frequency within each individual BA, providing proper reserves for balancing generation and demand in real time, providing reserves for primary frequency response, and providing reserves for restoring resource-to-demand balance within 15 minutes following a sudden loss of a designated load following generating unit or disturbance event on the BA and on the Eastern Interconnection generally.

The BAL standards are important reliability standards, because they regulate a BA's performance with respect to maintaining proper reserves to balance resources and demand in real time and to provide for proper frequency regulation within its operating boundary, to control a BA's impact on the reliability of neighboring BAs across the interchange tie lines and the regional Interconnection generally. Importantly, a BA's failure to comply with these mandatory reliability standards could result in system emergencies and reliability failures, such as unscheduled power flows, unnecessary and

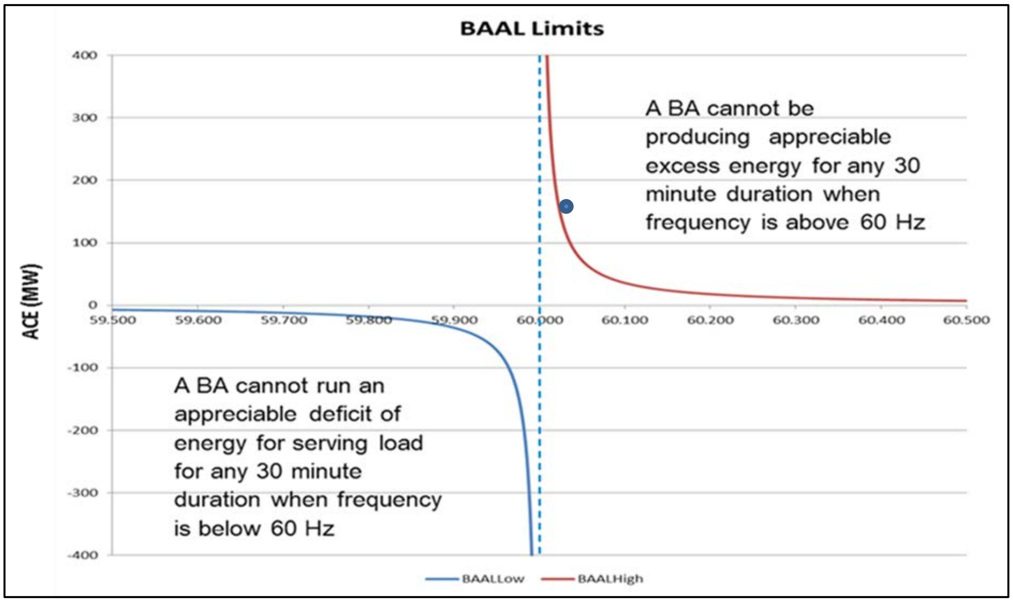
[4] There are two requirements associated with BAL-001. The current version of the BAL-001 standard, BAL-001-2 became effective on July 1, 2016, and requires each BA to operate such that its clock-minute average of Reporting Area Control Error does not exceed its clock-minute Balancing Authority ACE Limit [BAAL] for more than 30 consecutive minutes for the applicable Interconnection in which the BA operates. Source: NERC Reliability Standard BAL-001-2, Real Power Balancing Control Performance, Enforcement Date: 7/1/2016. *Available at:* http://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx (United States, BAL-001-2).

automatic firm load shedding, or in a worst-case scenario, cascading outages across the Interconnection. The NERC reliability standards are also enforceable by FERC, and violations are subject to a civil penalty of up to $1,000,000 per violation for each day that it continues.

Q. PLEASE EXPLAIN HOW A BALANCING AREA WITH VARIABLE AND INTERMITTENT ENERGY FROM SOLAR QFs PUTS THE BA AT INCREASING RISK OF VIOLATING THE BAL-001-2 STANDARD.

A. Figure 6 shown below depicts a BA's requirement under NERC to maintain its frequency within normal limits on a consecutive 30-minute basis. If a BA experienced too much energy relative to real-time load in the BA, causing frequency to rise above the scheduled frequency (60 Hz), the BA would be operating in the upper right quadrant of the Figure 6 graph. Conditions promoting this scenario are increasingly occurring on the DEP BA as variable and essentially uncurtailable (except in emergency condition scenarios) solar QFs continue to inject unscheduled and unconstrained energy into the BA in excess of DEP's physical limitations to absorb energy. As explained above, DEP can ramp down its load following generating resources to the LROL of its Security Constrained Unit Commitment; however, during the mid-day lowest demand period, DEP cannot further reduce its dispatchable resources, and the solar QF energy causes excessive energy on the DEP BA. If DEP were unable to mitigate the excess energy, its system would be in the upper right quadrant, operating with compromised reliability and creating potentially harmful unscheduled power flows with neighboring BAs.

Figure 6



Similarly, if a BA experienced a deficit in energy relative to real-time demand in the BA, causing frequency to drop below the scheduled frequency (60 Hz), the BA would be operating in the lower left quadrant of the Figure 6 graph. Conditions for this circumstance are also currently occurring on the DEP BA as solar QF energy is suddenly withdrawn due to sudden cloud cover or when QF energy suddenly ramps down during the late afternoon period at the same time customer demand is increasing. System operating scenarios where the BA could experience a deficit of energy include a change in weather (*i.e.* such as cloud cover on a sunny summer afternoon that routinely occurs in the Carolinas), a quick increase in customer demand during the late afternoon period when solar energy drops off, or the loss of a sizable network generating resource. Under such conditions, DEP's system would be in the lower left quadrant, operating with compromised reliability.

Q. HOW DOES THE SYSTEM OPERATOR MANAGE THIS RISK?

A. To manage the risks from operational excess energy the system operator utilizes more operating reserves to ensure compliance with NERC's BAL 001-2 standard. Similar to the warning that a system operator is given when a power flow through a transmission line is approaching its system operating limit, the system operator is maintained situationally aware of ACE exceeding the BAL-001-2 limit by audible alarms. The system operator receives the first alarm when ACE has exceeded the BAL-001-2 BAAL limit for 5 consecutive minutes. At this point, the system operator would take actions such as reducing or increasing on-line generation (through manual intervention if necessary). If the ACE continued to exceed the BAAL, the operator would continue to receive alarms every 5 minutes, possibly leading to more emergent actions such as curtailing solar output for excess energy emergencies. In line with the 5-minute interval BAAL exceedance alarms the operator receives and acts upon, I deem the 5-minute balancing approach that Astrapé takes in its Solar Integration Service Charge cost analysis to be reasonable from a system operator's perspective.

Q. PLEASE EXPLAIN HOW VARIABLE AND INTERMITTENT SOLAR QF ENERGY ALSO CHALLENGES COMPLIANCE WITH BAL-002 AND BAL-003 STANDARDS.

A. The BAL-002 Standard requires a BA to provide contingency reserves within 15 minutes of the loss of a designated network generating resource to restore the "resource-to-demand" balance that existed just before the loss of the resource. Variable and intermittent resources, such as solar generators, delivering dynamically changing output levels in an unscheduled or uncontrolled manner during the 15-minute recovery period could contribute to the occurrence of a BAL-002 violation. The reliability risks associated with the BAL-002 requirement to recover to pre-disturbance resource-to-demand balance levels within 15 minutes is similar to the BAL-001-2 Standard, in that resource-to-demand imbalance leads to frequency excursions on the Eastern Interconnection and unscheduled power flows between the BA experiencing the loss of resource and its neighboring BAs. With the variability and intermittency of unscheduled solar generation, the solar output being injected into the system can significantly decline at the critical time that the BA is trying to recover from a loss of a base load generator, such as a nuclear resource, thus leading to an increased risk of violating the NERC BAL-002-2 standard.

The BAL-003 standard defines the amount of frequency response needed from BAs to maintain Interconnection frequency within defined bounds, and includes requirements for the measurement and provision of frequency response. The BAL-003 standard establishes a minimum frequency response obligation for each BA, provides a uniform calculation of frequency response, establishes frequency bias settings that set values closer to actual BA frequency response, and encourages coordinated automatic generation control operation. By this standard, NERC requires BAs to provide primary frequency response to mitigate susceptibility to under-frequency load shedding actuation that sheds firm load. During periods of high solar energy output (blue sky days), the excess energy provided by these asynchronous resources force the de-commitment of inertial resources with governors that provide primary frequency response, thus reducing the amount of available frequency response required of the BA. Additionally, inertial resources with governors are less capable of providing governor actions at minimum loads which also impacts the DEC and DEP BAs ability to provide the required frequency response needed to maintain reliable operations and compliance with the NERC balancing requirements.

As noted in my discussion of the BAL-001-02 requirements above, significant penetrations of uncontrolled and effectively non-curtailable solar QFs on a system, such as is now being experienced in DEP, increase the risk of deficit energy conditions relative to load demands, which are a leading cause of low frequency disturbances on a BA.

Q. WHY IS A FUNDAMENTAL UNDERSTANDING OF BALANCING AREA AND THEIR RESPONSIBILITIES RELATED TO THE NERC BAL STANDARDS IMPORTANT TO YOUR REBUTTAL TESTIMONY?

A. ORS Witness Horii refers to the additional ramping capability and reserves needed to integrate increasing amounts of solar into a BA. There is a direct correlation between integrating solar, the resulting additional ramping capability and operating reserves needed, and compliance with NERC's BAL Standards as will be shown later in my rebuttal testimony. Moreover, SACE/CCL Witness Kirby refers to using off-line contingency reserves in lieu of on-line synchronous operating reserves for ensuring compliance with NERC's BAL standards. Understanding the three NERC BAL standards aforementioned and what BAs must do to ensure compliance with these standards is imperative to showing that Witness Kirby's argument is not sound. Also, Witness Kirby's assertion that the system operator can just use the full 30 consecutive minute period to economically optimize the control of generation resources for meeting compliance with the NERC Standard BAL-001-2 Balancing Authority ACE Limit requirement is flawed since inaction for even 5 to 10 minutes with respect to balancing demand and resources can lead to an increase in unscheduled power flows. Additionally, if a system operator waited until 20 consecutive BAAL-low exceedance minutes to occur to take mitigating actions and then incurred the loss of a large generator, the operator would be significantly at risk of potential non-compliance with the NERC BAL-001-2 requirements.

Last, SBA Witness Burgess argues that the DEP-West Balancing Authority Area (BAA) is operated separately from DEP-East and thus should not be considered in the DEP avoided coat rate. Once again, a fundamental understanding of how the DEP BA maintains and uses reserves to comply with the NERC BAL standards will show that Witness Burgess does not understand how the DEP BA responsibilities are met through coordinated operation of the DEP-East and DEP-West BAAs.

Q. IN YOUR ROLE AS A SYSTEM OPERATOR, HAVE YOU INVESTIGATED THE INCREASED COSTS OF CARRYING ADDITIONAL ONLINE OPERATING RESERVES ATTRIBUTABLE TO INTEGRATING SOLAR QFS INTO THE DEC AND DEP BALANCING AREAS, WHICH IS AN ISSUE OF CONTENTION BEFORE THE COMMISSION?

A. No. Quantifying the "integration costs" of operating the DEC and DEP BAs to respond to the operational challenges that the Companies are now managing as additional unscheduled and unconstrained QF solar is installed is beyond the scope of my responsibilities. I am, however, aware that members of my team, including my Director of System Operations for DEC and DEP, provided technical support and input into Astrapé Consulting's Solar Ancillary Services Study ("Study"). The purpose of my rebuttal testimony is to respond to operational arguments raised by other parties and to generally corroborate the conclusions of the Study that the Companies are now required to carry increased operating reserves in order to manage the operational impacts of unscheduled and uncontrolled solar generation being injected into the DEC and DEP BAs. Mr. Nick Wintermantel of Astrapé Consulting and Mr. Glen Snider of Duke Energy directly support the Study.

IV. RESPONSE TO ORS WITNESS HORII

Q. HAVE YOU REVIEWED ORS WITNESS HORII'S RECOMMENDATIONS FOR DUKE ENERGY TO PURSUE SYSTEM OPERATIONAL INITIATIVES TO POTENTIALLY "MINIMIZE" SOLAR INTEGRATION COSTS?

A. Yes. Witness Horii makes three recommendations that Duke could evaluate in an effort to reduce the integration costs now being experienced in the DEC and DEP BAs to integrate QF solar:

1) If additional operating reserve requirements were dynamically linked to solar output levels and the varying risk of solar output reductions;
2) Employing improved solar output forecast methods to reduce the forecast error between expected and actual solar output; and
3) Employing pre-curtailment of solar to reduce the cost to address solar overforecast error.

Q. PLEASE RESPOND TO MR. HORII'S FIRST TWO RECOMMENDATIONS.

A. Duke Energy, as a member of the Electric Power Research Institute's Balancing and Uncertainty Task Force along with members from CAISO and HELCO, is on the forefront of managing the challenges of integrating significant levels of uncontrolled solar QF generation and is continuously looking for ways to improve system operations and reduce operational costs for customers while ensuring compliance with the NERC reliability standards. Duke is also continuing to refine and improve its solar output forecast methods to reduce the forecast error between expected and actual solar output. Recent solar forecast modeling refinements include deploying new software in spring 2019 to customize solar farm forecasts with site characteristics that best match the solar generation injected at each site. This recent forecasting improvement has resulted in more accurate generation forecasts from solar sites throughout the DEC and DEP BAs. Duke is also participating in a U.S. Department of Energy-funded study designed to develop probabilistic solar forecasts and, once completed, could allow for optimized system dispatch based on the results of the study. Accordingly, Duke will continue to look for ways to improve solar forecasting and cost-effective system operations to respond to the solar integration challenges I have discussed in my testimony.

Q. PLEASE RESPOND TO ORS WITNESS HORII'S THIRD RECOMMENDATION THAT DUKE UNDERTAKE "PRE-CURTAILMENT OR UNDER-SCHEDULING" OF SOLAR RESOURCES TO REDUCE THE INCREMENTAL OPERATING RESERVES REQUIRED TO RESPOND TO THESE GENERATORS' INTERMITTENCY AND VOLATILITY.

A. Mr. Horii explains at page 21 of his testimony that:

> Pre-curtailment is the recognition of expected curtailment levels in scheduling solar generation in order to reduce the need for increased operating reserves. If it is anticipated that solar would be curtailed on the operating day due to oversupply, utility system operators could reduce the amount of additional reserves they would otherwise procure to accommodate a potential solar over-forecast."

I appreciate Mr. Horii's suggestion, as this is effectively how the Companies operate Duke Energy's fleet of solar generators today. DEP's and DEC's utility-owned facilities are fully integrated into the Companies' operational planning and dispatch and are built with central control dispatch down capability that provides DEP and DEC system operators with real-time control over those facilities' output when necessary to balance BA load and resources. I certainly believe there would be merit to allowing the Companies to schedule both utility-owned and third-party solar generation in order to reduce operationally excess energy that is increasingly being experienced and will increasingly require curtailment in the future. Unfortunately, however, under the PURPA regulatory framework, DEC and DEP are limited to curtailment of solar QFs only in system emergency conditions, unless the QF agrees to curtailment as part of the purchase arrangement.

Q. RECOGNIZING THAT DUKE IS LIMITED UNDER PURPA FROM REQUIRING "PRE-CURTAILMENT OR UNDER-SCHEDULING" OF QF SOLAR RESOURCES, PLEASE EXPLAIN HOW DUKE MANAGES THESE ISSUES TODAY.

A. Today the Companies operate under a standardized "dispatch-curtailment protocol," which the Companies' system operators will follow when confronted with a potentially-imminent system emergency on the DEC or DEP BA. As shown in Figure 7 below, the protocol starts with Tier 1 system operator actions to reduce the output from the Companies' traditional resources such as fossil fuel generators and hydroelectric generators down to their LROL. Tier 2 and

Tier 3 prioritize curtailment of the Companies' non-PURPA resources including the "full dispatch control" under Competitive Procurement of Renewable Energy ("CPRE") Program PPAs followed by curtailment and/or "operational dispatch control" of larger QFs under the Companies' bilateral negotiated PPAs. Tier 4 emergency action/curtailment would be called upon in response to an imminent system emergency where the system operator's Tier 1, 2, and 3 actions do not alleviate the potential system emergency condition on the system. Finally, reducing nuclear plant output in real time would be taken as a last resort action.

Figure 7

Dispatch-Curtailment Protocol
Tier-1
§Routine actions with DEP/DEC assets
Tier-2
§Atypical Unit Operation
§CPRE/LCP Full Dispatch Control (10% DEP, 5% DEC)
Tier-3
§Legacy Bilateral PURPA PPA/RPPA Operational Dispatch Control (5% or Total Hour Limit)
Excess Energy Emergency Action/Curtailment
Tier-4
§System Emergency – Cogeneration/PURPA(PPA and Standard Offer)/RPPA/CPRE Agreements
Last Resort Action
Tier-5
§Emergency – Nuclear Reduction

Absent changes in the PURPA framework to allow increased operational control over QF solar, the Companies' system operators will continue to manage the growing challenges of increasing levels of unscheduled and unconstrained QF solar creating operational excess energy under this process.

Q. COULD QFs AGREE TO ALLOW THE UTILITY ENHANCED RIGHTS TO DISPATCH, OPERATE, AND CONTROL THEIR GENERATING FACILITIES AS PART OF A PURCHASE CONTRACT?

A. Yes, and that would be a significant benefit from the system operator's perspective. Notably, the Companies' CPRE Program provides for enhanced rights to dispatch down QF facilities in the same manner as utility-owned solar facilities and, from my perspective as a system operator, is a key benefit of that program's design.

At high levels of solar QF penetration, it is critical that the BA system operator have operational dispatch down control over generators in order to provide reliable electric service. Under the PURPA construct, the system operator does not have this essential, operational control, and is increasingly being challenged to manage the levels of solar QF energy being injected into the BA in real time.

V. RESPONSE TO SACE/CCL WITNESS KIRBY

Q. SACE/CCL WITNESS KIRBY EXTENSIVELY DISCUSSES THE NERC BAL STANDARDS. DO YOU HAVE ANY GENERAL COMMENTS REGARDING HIS VIEWS BASED UPON YOUR RECENT EXPERIENCE INTEGRATING QF SOLAR INTO THE DEC AND DEP BAs?

A. Yes. Mr. Kirby presents a generally reasonable understanding of the NERC Balancing Standards. However, I do not agree that his analyses presents a fair and accurate picture of the challenges now being managed on DEC and DEP BAs in order to integrate the unparalleled levels of unscheduled and unconstrained QFs solar that I discuss above.

For example, Witness Kirby's assertion that the system operator can use the full 30 consecutive minute period to economically optimize the control of generation resources for meeting compliance with the NERC Standard BAL-001-2 Balancing Authority ACE Limit requirement is flawed since inaction for even 5 to 10 consecutive BAAL exceedance minutes with respect to balancing demand and resources can lead to increased unscheduled power flows creating reliability risks. Unscheduled power flows are a recognized concern for FERC and NERC, and DEC and DEP do not operate their BAs in manner that exacerbates increased frequency deviations and unscheduled power flows on to neighboring BAs.[5] Additionally, if a system operator waited until 20

[5] Real Power Balancing Control Performance Reliability Standard, 149 FERC ¶ 61139 (2014).

consecutive BAAL-low exceedance minutes occurred to take mitigating actions and then incurred the loss of a large generator, the operator would be significantly hindered with respect to complying BAL-001-2 most likely leading to a violation of the BAAL standard. Again, the reliability risks of unscheduled power flows on the DEC and especially DEP systems are also more significant due to the significant penetration of unscheduled and unconstrained solar being injected into the system, which Mr. Kirby may not have taken into account.

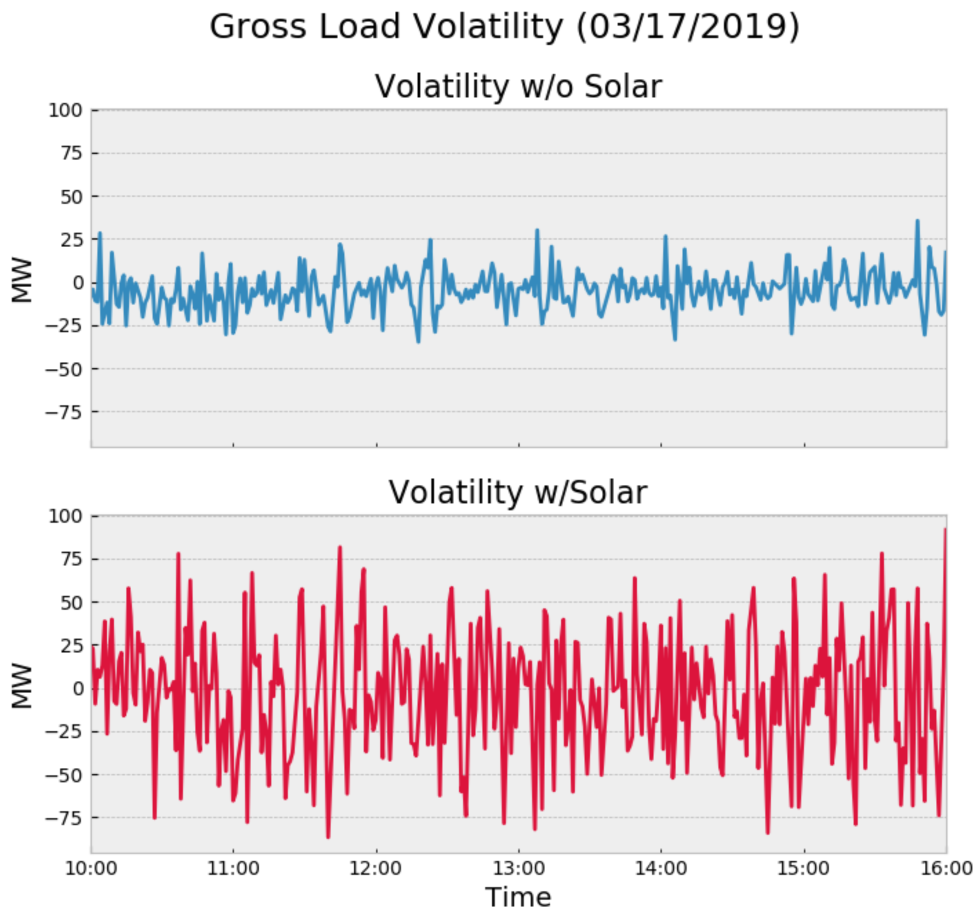
Q. IN YOUR EXPERIENCE, IS MR. KIRBY CORRECT THAT OPERATING UNDER THE NEW 30 CONSECUTIVE CLOCK-MINUTE BAL-001-2 REQUIREMENTS IS LESS STRINGENT THAN THE PRIOR CPS2 STANDARD?

A. No. Witness Kirby’s suggestion that the BAL-001-2 requirements allow the system operator more flexibility as compared with the old CPS2 metric is flawed and does not reflect operational experience in the DEC and DEP BAs since the BAL-001-2 requirement become effective in 2016. Looking back at my Figure 6, there is a dot to the right of the red curve. According to Witness Kirby’s assertion, BAAL would allow the operator more freedom to operate with an Area Control Error or “ACE frequency deviation” at this point as compared with CPS2. However, should the operator not adjust his ACE lower within the 30-minute window allowed by the standard, a violation of BAL-001-2 would occur. In contrast, the operator could operate at this point continuously for several hours and still be able to comply with the monthly CPS2 requirement imposed by the old BAL-001 version 1 standard.

Q. IN ADDITION TO PRESENTING HIS CONCERNS WITH THE ASTRAPÉ STUDY, WHICH IS BEING ADDRESSED BY OTHER DUKE WITNESSES, WITNESS KIRBY ALSO TESTIFIES THAT UTILIZING OFF-LINE CONTINGENCY RESERVES WILL LOWER THE COST OF OPERATING RESERVES NECESSARY TO COMPLY WITH NERC's BAL STANDARDS. DO YOU AGREE?

A. No. I do not agree with Witness Kirby's assertion for the following reasons. First, in order to ensure compliance with NERC Standard BAL-001, Duke's system operator utilize on-line operating reserves to manage the constant minute-to-minute load and solar volatility to ensure the DEC and DEP BAs do not exceed the ACE limits prescribed by NERC for 30 consecutive minutes. Looking at my Figure 8 below, you can see the volatility of MW created by load and solar. This volatility continues to increase as more QF solar is added to the system.

Figure 8



Mr. Kirby’s recommendation to rely upon off-line contingency reserves is not reasonable based upon my real-world operational experience. If Duke planned and dispatched its generating fleets to manage this volatility in order to maintain its resource – demand balance with off-line contingency reserves, the system operator would be required to start fast-start CTs several times intra-hour—which is beyond their operational design capabilities. Moreover, while these CTs were responding to the solar volatility, they would no longer be “reserves” available for responding to a disturbance (i.e. loss of a large generator) thus either subjecting Duke to increasing risk of a NERC BAL-002 standard violation or requiring the operator to maintain even more on-line spinning reserves to be capable of reliably responding to a potential future disturbance.

Second, NERC Standard BAL-002 requires that the BA recover to pre-disturbance resource – demand balance levels within 15 minutes from the start of the disturbance (i.e. loss of a large generator). If you do not have many of these events on an annual basis, then it makes sense to have most of these contingency reserves off-line ready to respond to the disturbance in a very short time period to meet the NERC BAL-002 requirements to rebalance within 15 minutes. Indeed, this is how Duke manages its contingency reserves to respond to such events today. However, as I explain above, the operational parameters that support maintaining contingency reserves off-line is inapplicable to managing the operating reserves needed to manage the growing inter-hour volatility of QF solar on the DEC and DEP BAs. Accordingly, Mr. Kirby's recommendation that the Companies rely upon off-line contingency reserves to manage the integration costs of solar QFs is not reasonable from a system operator's perspective.

VI. RESPONSE TO SBA WITNESS BURGESS

Q. SHOULD THE DEP-EAST AND DEP-WEST BALANCING AUTHORITIES AREAS ("BAAs") BE TREATED AS SEPARATE BAs FOR DETERMINING THE DEP AVOIDED COST RATE?

A. No. Contrary to Witness Burgess' assertion, the DEP-East and DEP-West BAAs should not be treated as separate BAs. DEP is responsible for operating

DEP-East and DEP-West as a single BA and commits and operates the utility's generating fleet on an integrated basis to serve load across the DEP BA. DEP reserves a 400 MW firm transmission path between the DEP-East and DEP-West BAAs. From an operations perspective, this firm transmission of energy is no different from native load resources in North Carolina, such as the H.F. Lee Combined Cycle generator located in Goldsboro, NC (in the DEP-East BAA), reliably serving load for the DEP customers in both North Carolina and South Carolina, including the DEP-West BAA. In addition, DEP employs a dynamic transfer for exchanging economic energy as well as load following/regulation service between DEP-East and DEP-West, thus allowing operation of the two BAAs as one BA. More specifically, when the DEP-West load increases intra-hour the dynamic transfer will increase if energy in DEP-East is cheaper than DEP-West, and likewise, if energy in DEP-West is cheaper than DEP-East the dynamic transfer will decrease. Also, should DEP-West need sudden load following/regulation service, the dynamic transfer will respond in the needed direction to accommodate this need.

Q. ACCORDING TO WITNESS BURGESS, QF SOLAR CAN BE USED AS A DISPATCHABLE RESOURCE TO PROVIDE REGULATION AND LOAD FOLLOWING SERVICES. DO YOU AGREE?

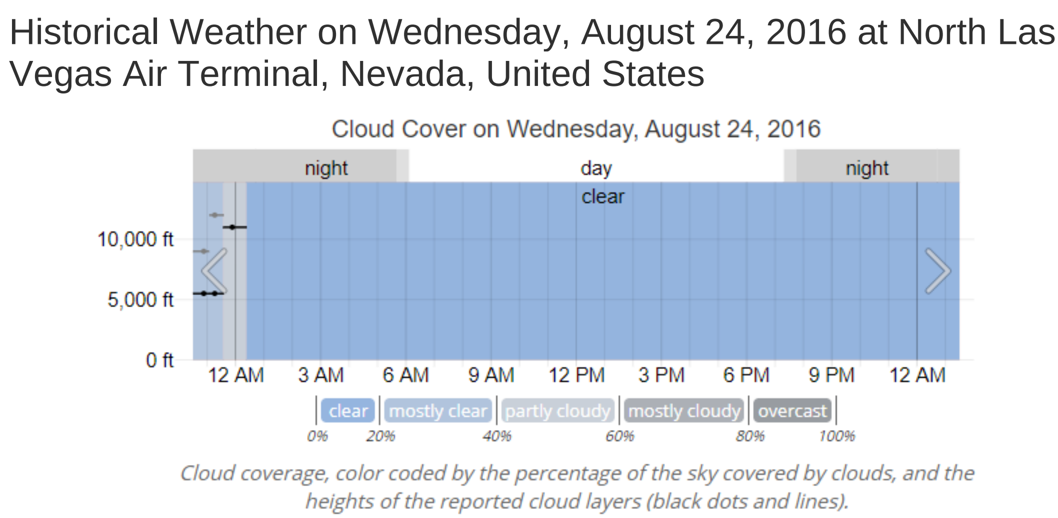
A. No, I do not agree. As mentioned previously in my rebuttal testimony regulation and load following resources are available when needed to respond to variability in system load demand and the increasing intermittency and variability of solar generation. According to Witness Burgess, QF solar can be used as a dispatchable resource to provide regulation and load following services citing results from a one-day demonstration at a 300 MW First Solar plant in CAISO. From my perspective, significantly more evaluation and operational experience would be needed to validate that solar resources can provide ancillary service to the DEC and DEP BAs in the Carolinas.

The study referenced by Mr. Burgess was conducted on a blue sky day in the CAISO at the 300 MW First Solar Desert Stateline Solar Facility located near the California – Nevada state line in CAISO. Based upon some preliminary research, operating conditions at the project site look to be significantly more favorable than operating conditions in the Carolinas. Looking at historical cloud cover data (Figure 9) for August 24, 2016, the day the regulation service test was conducted, shows the day to be a clear, blue sky day for Las Vegas, Nevada, a location within several miles of the facility. Thus, the output of the facility was easy to forecast for the daylight period. Indeed, for both the morning and the mid-day regulation test periods the solar facility experienced clear, blue-sky conditions making the regulation capability of the facility very predictable. However, Figure 10 shows the results for the regulation test in the afternoon period from page 19 of the Study.[6] This figure shows that the solar output was interrupted for two short periods with the passage of a couple of clouds; the first instance shows the solar output dropped by 60 MW in approximately 1 minute and the second instance shows the output

[6] NREL, Demonstration of Essential Reliability Services by a 300-MW Solar Photovoltaic Power Plant (March 2017) *Available at* https://www.nrel.gov/docs/fy17osti/67799.pdf.(last visited Oct. 2. 2019).

dropped by at least 160 MW in approximately 2 minutes. During these periods, the operational uncertainty of this very large 300 MW solar PV plant dropping 160 MW in output in an unscheduled manner over a two-minute period under seemingly optimal weather conditions, I have significant concerns that Mr. Burgess' conclusion that solar PV could provide reliable regulation capability based upon this Study is flawed. Contrast Figure 9 with Figures 11 and 12, the cloud cover in Raleigh, NC and Columbia, SC on the same day.

Figure 9[7]



[7] *Available at* https://weatherspark.com/h/d/145434/2016/8/24/Historical-Weather-on-Wednesday-August-24-2016-at-North-Las-Vegas-Air-Terminal-Nevada-United-States#Figures-CloudCover (last visited Oct. 1, 2019).

1 **Figure 10**

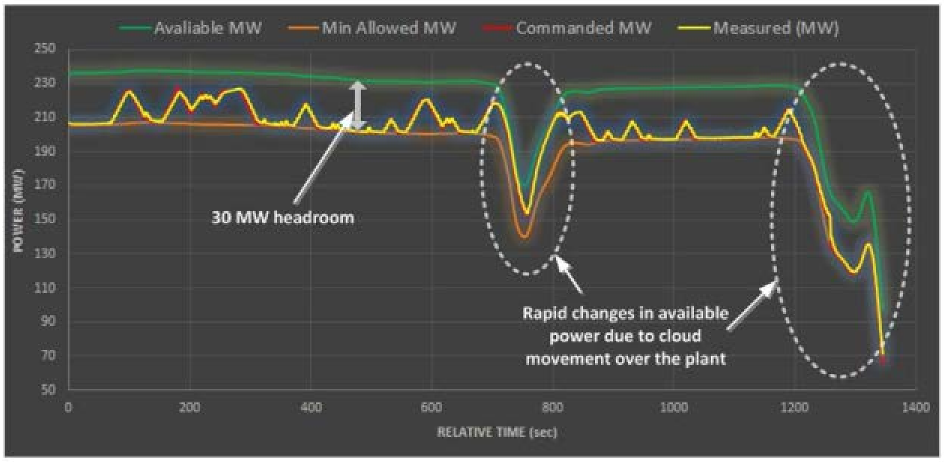
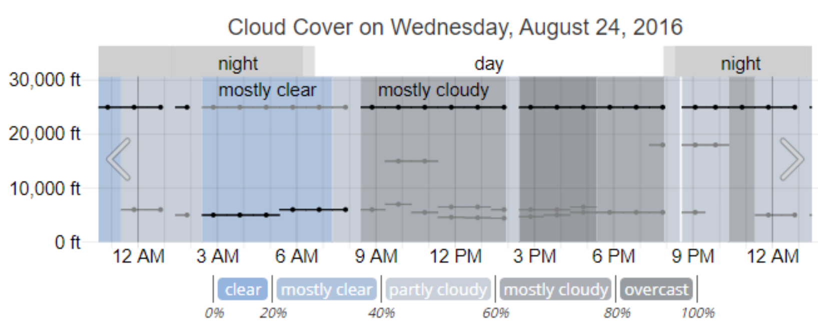


Figure 17. Afternoon AGC test (2:54 p.m.–3:16 p.m.). ***Illustration from NREL***

2 **Figure 11[8]**

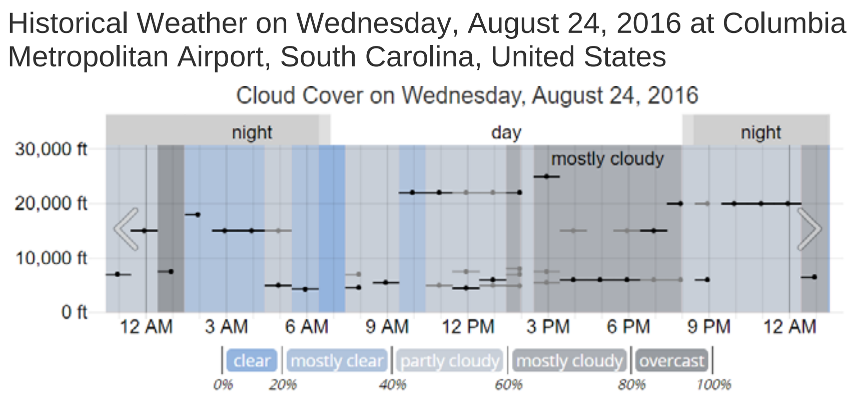
Historical Weather on Wednesday, August 24, 2016 at Raleigh-Durham International Airport, North Carolina, United States



Cloud coverage, color coded by the percentage of the sky covered by clouds, and the heights of the reported cloud layers (black dots and lines).

[8] *Available at* https://weatherspark.com/h/d/146992/2016/8/24/Historical-Weather-on-Wednesday-August-24-2016-at-Raleigh-Durham-International-Airport-North-Carolina-United-States#Figures-CloudCover (Last visited October 1, 2019).

Figure 12[9]



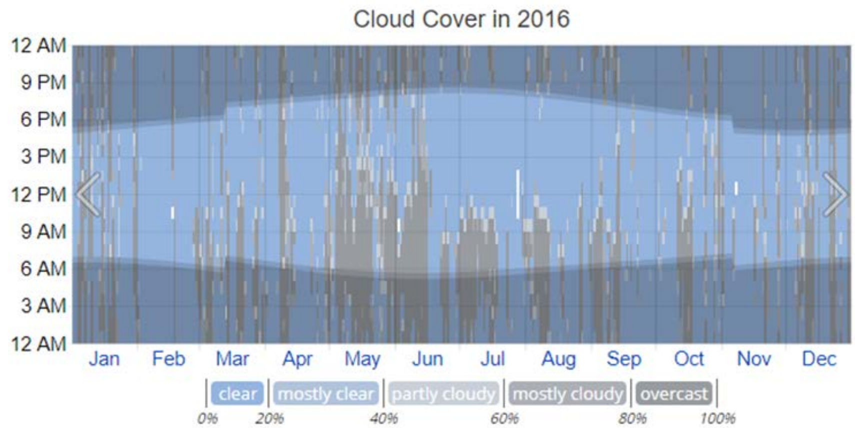
Cloud coverage, color coded by the percentage of the sky covered by clouds, and the heights of the reported cloud layers (black dots and lines).

The purpose of presenting these Figures is to show that, in the real world Duke BAs, it would now have been possible to get predictable regulation and load following service from a solar facility near Raleigh, NC and Columbia, SC on August 24, 2016. This difference in weather makes the Carolinas poorly suited for solar facilities to provide regulation and load following services because, unlike California, cloud cover makes the dependability and certainty in capability of solar facilities in the Carolinas very poor from day-to-day, hour-to-hour, minute-to-minute as reflected in my Figures 3, 4, and 8 above. Looking over a full year of hourly reported cloud cover, Figures 13, 14, and 15 demonstrate that cloud cover is much more of an issue in the Carolinas than in California, with California experiencing many more blue sky days annually

[9] *Available at* https://weatherspark.com/h/d/146825/2016/8/24/Historical-Weather-on-Wednesday-August-24-2016-at-Columbia-Metropolitan-Airport-South-Carolina-United-States#Figures-CloudCover(Last visited October 1, 2019).

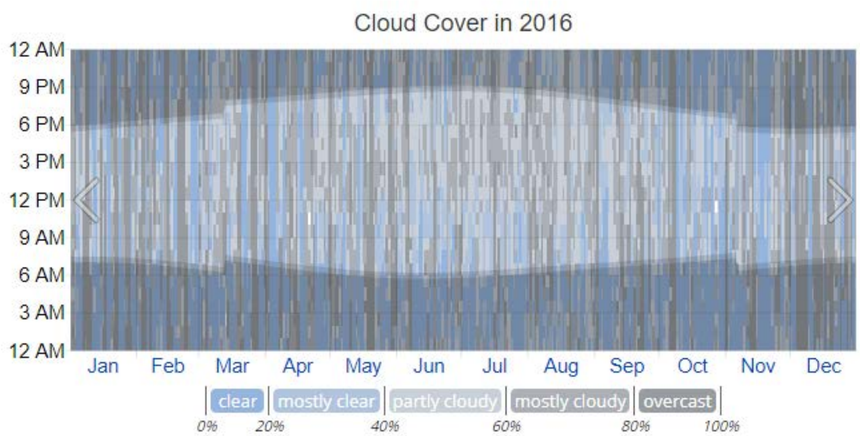
compared with the Carolinas thus the reason for the intermittency, variability, and volatility of solar output.

Figure 13 – 2016 Los Angeles, CA Cloud Cover



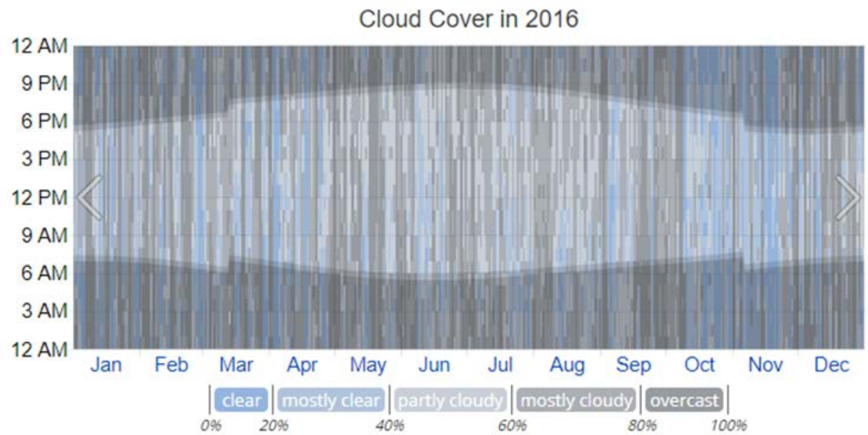
The hourly reported cloud coverage, categorized by the percentage of the sky covered by clouds.

Figure 14 – 2016 Columbia, SC Cloud Cover



The hourly reported cloud coverage, categorized by the percentage of the sky covered by clouds.

<u>Figure 15 – 2016 Raleigh, NC Cloud Cover</u>



The hourly reported cloud coverage, categorized by the percentage of the sky covered by clouds.

Q. PLEASE RESPOND TO WITNESS BURGESS' CONCLUSION THAT OPERATING RESERVES HAVE NOT INCREASED AS MORE SOLAR HAS BEEN INTEGRATED IN THE CAROLINAS.

A. Witness Burgess' conclusion that operating reserves have not increased as more solar has been integrated in the Carolinas is incorrect. Looking at my Figure 16, you will notice that there is an increase in coal generation in 2015 compared with 2016-2018 due to the lower cost of delivered coal and other factors at that time. When coal-fired units are committed, this usually results in the system operator keeping the unit on-line for several days due to the difficulty and potential for thermal stress issues from cycling coal-fired units. Since the coal units remain on-line through high and low load periods, this inflates the average operating reserves for 2015. From 2016 to 2018 when solar is increasingly being integrated (as indicated by the annual solar energy), more flexible operating reserve resources are committed and dispatched (CCs, CTs, and

Hydro) and increasing operating reserves are maintained to accommodate the variability and uncertainty from solar output. Thus, Witness Burgess has drawn an incorrect conclusion from the annual average operating reserve data he references in the table on page 81 of his direct testimony.

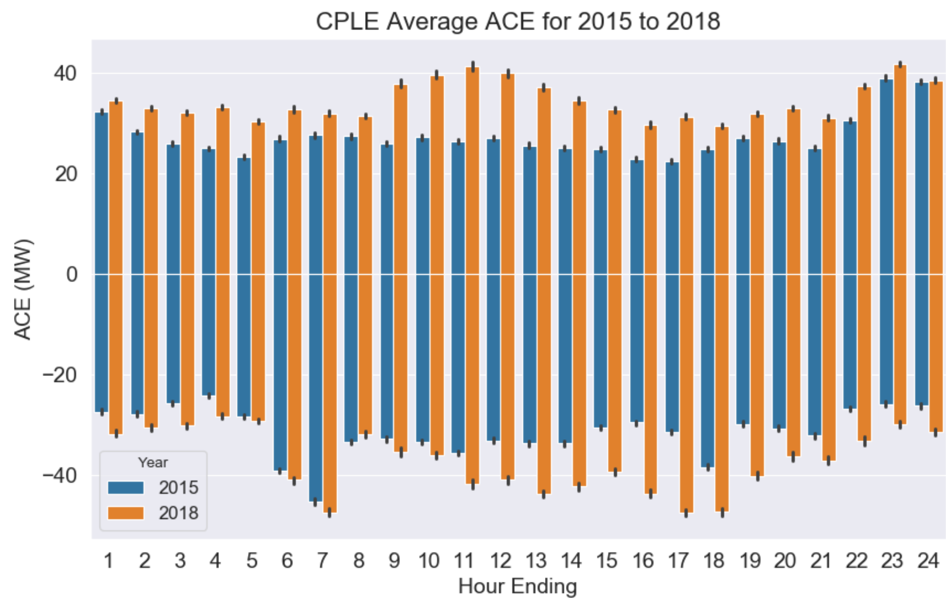
Figure 16

Year	Fuel Type	Net
2015	Coal	13,588,125
	Hydro	582,292
	Nuclear	28,284,481
	CT/CC	22,153,400
	Solar	411,653
	Cogen	1,585,742
	Total	66,605,693
2016	Coal	11,630,042
	Hydro	489,905
	Nuclear	29,333,963
	CT/CC	22,655,748
	Solar	1,671,852
	Cogen	1,816,395
	Total	67,597,905
2017	Coal	8,654,367
	Hydro	480,797
	Nuclear	29,504,561
	CT/CC	22,497,854
	Solar	2,990,300
	Cogen	1,910,914
	Total	66,038,793
2018	Coal	8,656,835
	Hydro	805,640
	Nuclear	27,490,999
	CT/CC	23,947,411
	Solar	3,600,361
	Cogen	1,786,114
	Total	66,287,360

Q. CAN YOU RESPOND TO WITNESS BURGESS' ASSERTION THAT DEP's DEP-East BAA AREA CONTROL ERROR NORMALLY DEVIATES +/- 200MW?

A. Yes. I will agree with Witneswess Burgess that ACE is the best indication of a BAAs balance of resources with demand; however, Witness Burgess' graph on page 75 of his testimony is misleading since it plots 105,120 data points into a narrow graph window, making it appear that +/-200 MW is the norm for the DEP East Area Control Error (ACE). A more appropriate graph for reviewing the normal ACE deviation is to look at the average for the positive (+) ACE deviations and the average for the negative (-) ACE deviations. Figure 17 shows these averages for each hour of the day for all of 2015 and 2018 for the DEP East BAA. This Figure shows the average ACE deviation in 2015 to be closer to +/-40 MW for each hour as compared with Witness Kirby's assertion of +/-200MW. In addition, 2018 ACE data was included to show the impact of unscheduled QF solar injections on the DEP-East ACE going from a low solar penetration year, 2015 to a much higher solar penetration year, 2018. Note the hours ending 09:00 through 17:00, the increase deviation of DEP East ACE reflects the volatility of solar as well as the net demand ramping impacts as referred to previously in this rebuttal testimony.

Figure 17



Mr. Burgess improperly draws inaccurate conclusions from a mischaracterization of operating data, while a more complete and accurate presentation of this data shows the impact of increasing solar volatility on system operations.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes it does.